ENERGEIA

LRMC Methodology Paper

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The Institute for Sustainable Future

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Contents

1 Introduction

The Institute for Sustainable Futures (ISF), via an Australian Renewable Energy Agency (ARENA) funded project, engaged Energeia to produce Long Run Marginal Costs (LRMCs) for four networks (Ergon Energy, Essential Energy, Powercor and Ausgrid) using a consistent, transparent and auditable approach and publicly available data as much as possible. Values were calculated at subtransmission (ST), high voltage (HV) and low voltage (LV) levels as well as for different network types (CBD, urban, short rural and long rural).

Although various approaches were considered for calculating LRMCs (see Appendix), an Average Incremental Cost (AIC)-based approach was adopted due to it satisfying ISF's requirements, being commonly employed by Distribution Network Service Providers (DNSPs), and its reduced complexity compared to other approaches. Furthermore, the publically available regulatory information notice (RIN) data published by DNSPs includes all key information needed to perform an LRMC calculation using an AIC-based method, meeting ISF's requirements of transparency (publically available data), consistency (data provided using the same calculation methodology) and auditability.

Energeia has accordingly developed an excel-based tool to calculate the LRMC values using an AIC-based approach.

This paper describes the structure and methodology used within Energeia's AIC tool to calculate the LRMC values. The paper is structured as follows:

- **Section 1 –** Provides an introduction on the background to the model

- **Section 2 –** Provides an Overview of the model,

- **Section** Error! Reference source not found. **–** Explains the mechanics of the AIC approach as implemented in the model

- **Section 8 –** Describes the assumptions and limitations of the model.

2 Tool Structure

In the tool, the inputs are located in the following tabs: *Input_AUS*, *Input_ESS*, *Input_PCR* and *Input_ERG*. The assumptions are listed in the *Assumptions* tab. The annual incremental demand is calculated in the *Demand* tab. The annual incremental augex, repex, connex and opex are calculated in the *Augex*, *Repex*, *Connections* and *Opex* tabs respectively, then combined to form annual incremental capex in the *Capex* tab. Capitalised network and corporate overheads are also added in the *Capex* tab. The AIC is calculated in the *LRMC* tab and the results are displayed in the *Summary* tab. Configuration of assumptions is possible in the *Assumptions* and *Summary* tabs.

3 LRMC Calculation

The tool calculates AIC for a given voltage level and network type in $/kVA/year according to the following formula:

$$AIC = \frac{NPV \ (Demand \ related \ capital \ cost, \$/year \ + Incremental \ O\&M, \$/year)}{NPV(Incremental \ network \ demand, kVA)}$$

Where:

- Demand related capital cost is the annual increment in capital expenditure (capex), assuming:

  - A capital recovery factor based on the real Weighted Average Cost of Capital (WACC), and

  - A configurable average asset lifetime

- Incremental O&M is the annual increment in Operations and Maintenance Costs, calculated as a configurable percentage of the incremental capital expenditure
- Incremental network demand is the year-on-year increase in demand in kVA.

The NPV and Capital Recovery calculations are carried out in real terms, using the real WACC as set by the Australian Energy Regulator (AER). The real WACC differs by DNSP.

Values are calculated at ST, HV and LV levels as well as for CBD, urban, short rural and long rural network types.

Sections 5 to 7 explain how each of the key components (incremental demand, incremental capex and incremental opex) are determined.

4 Inputs

The tool requires two types of inputs to derive the AIC values: fixed inputs and configurable inputs.

4.1 Fixed Inputs

The fixed inputs were predominately sourced from the RINs (Distribution Network Service Providers (DNSPs)), although the RINs were supplemented by other publicly available data where gaps existed. Figure 1 shows how the network AIC values are built up within the model and the corresponding sources of information for each component.

Figure 1 - Flow Chart Showing Calculation of Network AIC Values.
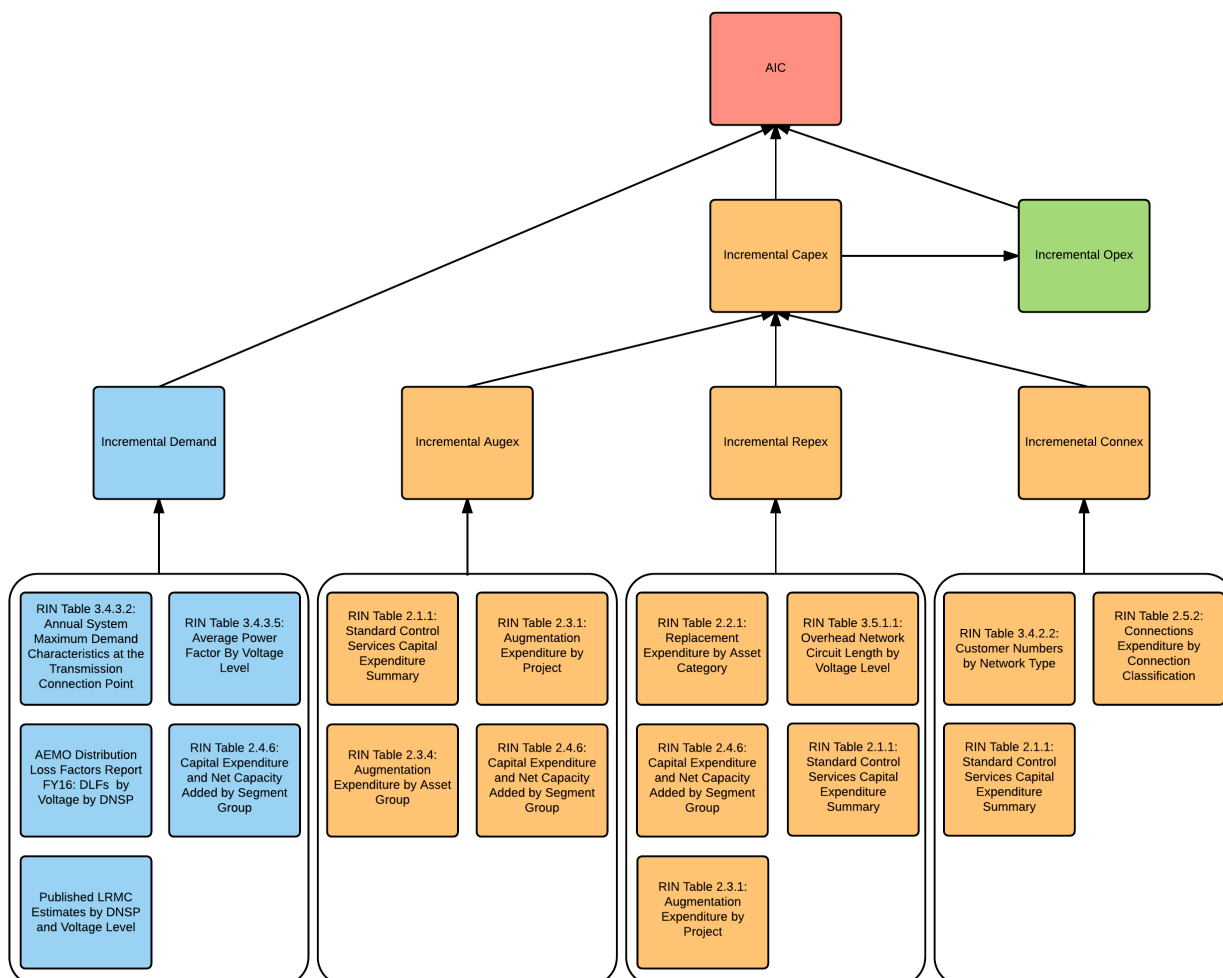
4.2 Configurable Inputs

The configurable inputs and their corresponding default values are listed in Table 1. See Sections 5 – 7 for further explanation.

Table 1 – Configurable Inputs and Their Corresponding Default Values

Configurable Input	Default Value
Include Connection Costs in AIC Calc	TRUE
Include CapCons in AIC Calc	FALSE
Augex Scaling Factor	100%
Demand Scaling Factor	100%
Time Horizon (years)	25
Max Demand Probability of Exceedance	10%
Average Asset Lifetime	40
Growth-Related Repex as Proportion of Total Repex by Voltage Level	
ST	2.5%
HV	2.5%
LV	2.5%
Opex as Proportion of Capex by Voltage Level	
ST	1.5%
HV	2.0%
LV	2.5%
Opex Scaling Factors by Year After Asset Commissioning	
0	0%
1	60%
2	0%
3	0%
4	40%

5   Incremental Demand

Energeia defines annual incremental demand as the additional coincident weather adjusted electricity peak demand measured at the meter (in MVA) that must be supported by the network each year. It excludes network losses and is a function of the number of customer connections, the average customer peak demand and the extent to which the peaks in customer demand coincide with the peak in network demand.

The tool calculates annual incremental demand at the system level using each DNSP's 5-year forecast for coincident weather adjusted system annual maximum demand (at the 10% and 50% probability of exceedance levels) aggregated at the transmission connection point in MW. To convert from MW to MVA, power factors specific to each DNSP and voltage level are applied[1]. To remove the network losses that are accounted for in the DNSP forecasts, distribution loss factors specific to each DNSP and voltage level are applied.

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[1] Power factors by voltage level are only publicly available for Powercor and Ergon; for Ausgrid and Essential Energy average overall network power factors are used.

5.1 Voltage Level Allocation

The voltage level allocation of system peak demand is based on scaling factors specific to each voltage level and DNSP that Energeia back-calculated from published DNSP LRMC estimates. Energeia modified the tool's default assumptions to match those of the DNSP where the DNSP's assumptions were provided; where the DNSP's assumptions were not provided, Energeia selected assumptions that produced the smallest discrepancy between the tool's LRMC estimates and the DNSP's LRMC estimates. Table 2 presents the unique set of assumptions for each DNSP examined (purple indicates the DNSP provided the assumption while red indicates Energeia provided the assumption). Figure 2 shows the difference between the tool's LRMC estimate and the DNSP's LRMC estimate at each voltage level, given the assumptions listed in Table 2 and Energeia's scaling factors.

Table 2 – Assumptions Used to Derive Scaling Factors to Separate System Demand by Voltage Level

Parameter	Ausgrid	Essential	Powercor	Ergon
System Demand POE	10%	50%	10%	10%
Time Horizon (years)	15	10	25	25
Connections Expenditure Included	TRUE	FALSE	FALSE	TRUE
Capital Contributions Included	FALSE	FALSE	FALSE	TRUE
Growth Related Repex as Proportion of Total Repex				
ST	2.5%	2.0%	2.0%	2.5%
HV	2.5%	2.0%	2.0%	2.5%
LV	2.5%	2.0%	2.0%	2.5%
Opex as Proportion of Capex				
ST	1.5%	0.0%	0.0%	1.5%
HV	2.0%	0.0%	0.0%	2.0%
LV	2.5%	0.0%	0.0%	2.5%

Source: Energeia, Ausgrid Tariff Structure Statement (TSS) 2015, Estimating the Average Incremental Cost of Ergon Energy's Distribution Network 2015, Estimation of Long Run Marginal Cost and Other Concepts Related to the Distribution Pricing Principles 2015

Figure 2 – Difference Between Model Estimates and DNSP Estimates for LRMC by Voltage Level
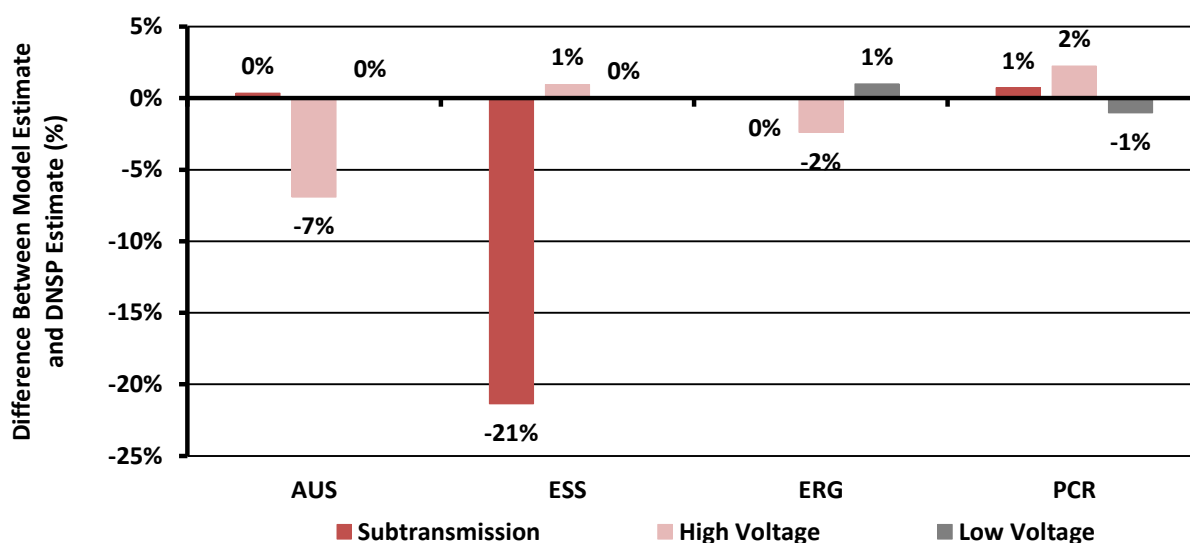
Source: Energeia, Ausgrid TSS 2015, Essential Energy TSS 2015, Powercor TSS 2015, Ergon Energy Long Run Marginal Cost Considerations in Developing Network Tariffs 2015

5.2 Network Type Allocation

To decompose annual incremental demand at each voltage level into CBD, urban, short rural (SR) and long rural (LR) annual incremental demand, the tool uses ratios derived from each network's Augex Model (RIN Table 2.4.6). As shown in Figure 3, RIN Table 2.4.6 contains a breakdown of capex and capacity added over the 5 year forecast period by network type for only two asset groups: distribution substations and HV feeders. Figure 4 maps each network type allocation to each asset group in RIN Table 2.4.6 for which there is a capacity added breakdown by network type.

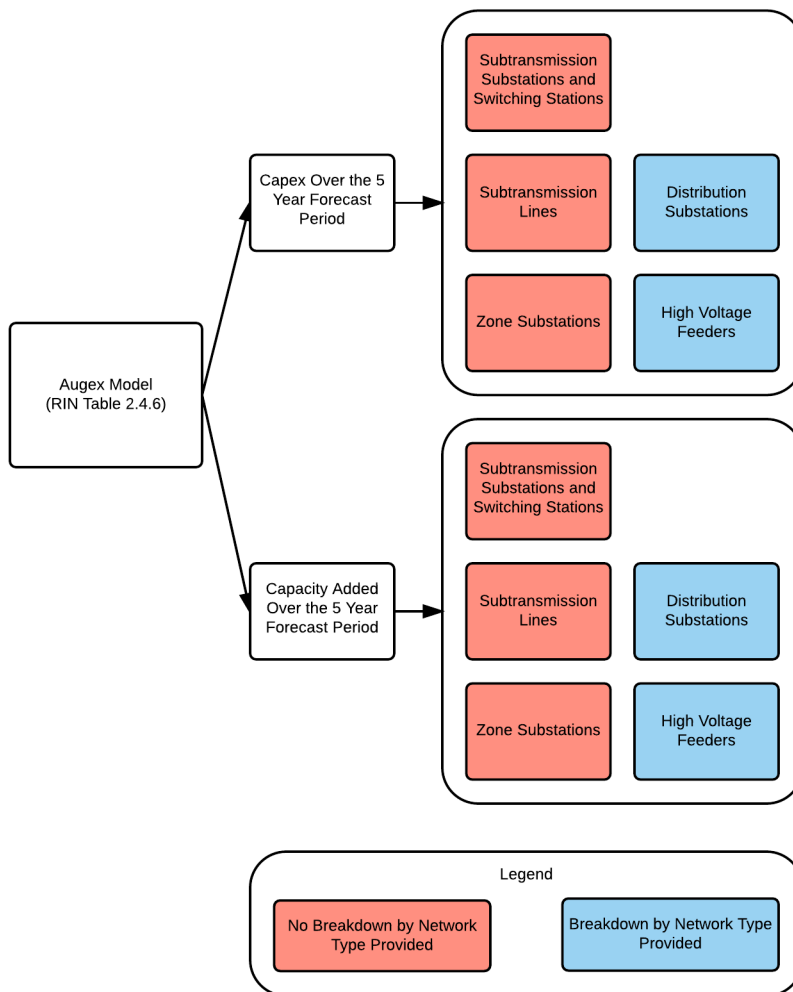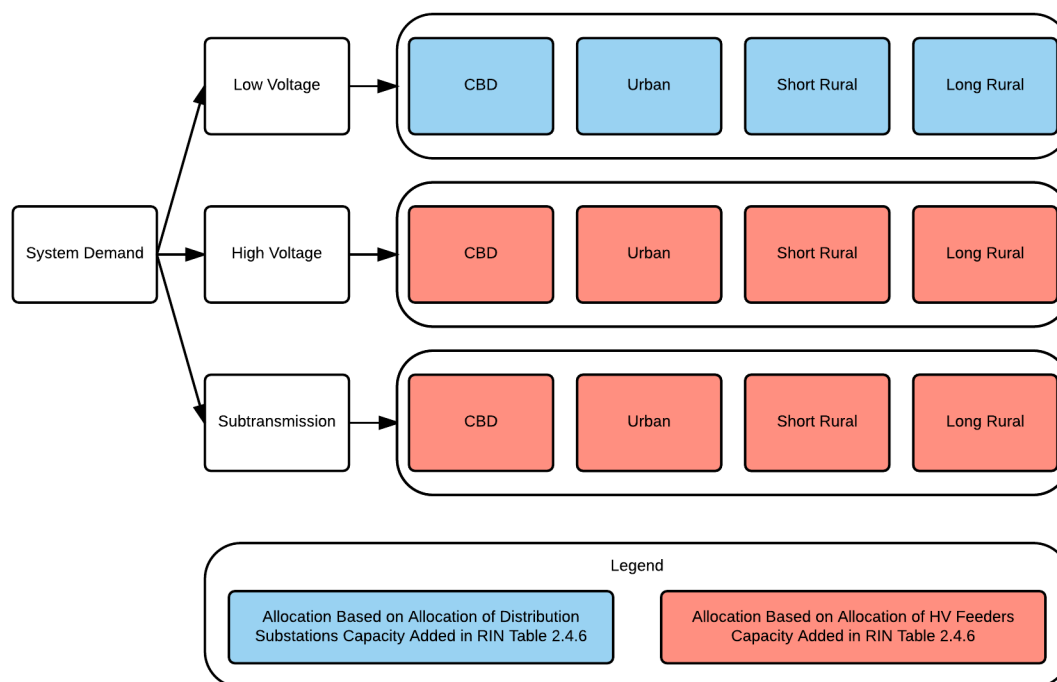*Figure 3 – Summary of Augex Model Outputs*

Figure 4 – Network Type Allocation of Demand Mapped to Asset Group in RIN Table 2.4.6

5.3 Projection

The annual incremental demand forecasts are projected 20 years using the average growth rate over the 5-year forecast period to represent demand over the long term. However, the time horizon is configurable – the shorter the time horizon, the more weight is given to the DNSP's 5 year forecasts.

In the tool, the demand scaling factor can be adjusted to reflect the user's view on how representative the DNSP's 5 year forecast peak demand is of the long term average. If the user considers the DNSP's 5 year forecast demand to be above average, this percentage should be set to below 100%; it should be set to above 100% if the user considers the DNSP's 5 year forecast demand to be below average. Changing the demand scaling factor only affects the demand forecast after the first 5 years.

6   Incremental Capex

Growth-related capex is composed of augmentation expenditure (augex), a proportion of replacement expenditure (repex), connections expenditure (connex) and capitalised network and corporate overheads.

6.1 Incremental Augex

AER defines annual incremental augex as the additional capital expenditure required to build or upgrade network assets to support changes in demand or to maintain quality, reliability and security of supply in accordance with legislated requirements[2].

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[2] AER Better Regulation: Expenditure Forecast Assessment Guideline for Electricity Distribution, p18

6.1.1 Voltage Level Allocation

Augex is summarised in RIN Table 2.3.4. RIN Table 2.3.1 is used to separate augex on subtransmission substations and switching stations from augex on zone substations. This separation is necessary, given the tool's assumption that subtransmission substations and switching stations are part of the subtransmission network while zone substations are part of the high voltage network. Table 3 shows how each entry in RIN Table 2.3.4 is allocated to a voltage level.

Table 3 – Stratification of Asset Categories by Voltage Level

RIN Table 2.3.4 Asset Group	Energeia Model Asset Group	Voltage Level
Subtransmission Lines	Subtransmission Lines	Subtransmission
Subtransmission Substations, Switching Stations, Zone Substations	Subtransmission Substations, Switching Stations	
	Zone Substations	High Voltage
HV Feeders	HV Feeders	
HV Feeders - Land Purchases and Easements	HV Feeders - Land Purchases and Easements	
Distribution Substations	Distribution Substations	Low Voltage
Distribution Substations - Land Purchases and Easements	Distribution Substations - Land Purchases and Easements	
LV Feeders	LV Feeders	
LV Feeders - Land Purchases and Easements	LV Feeders - Land Purchases and Easements	
Other Assets	Other Assets	N/A

6.1.2 Network Type Allocation

To decompose augex at each voltage level into CBD, urban, SR and LR augex, the tool uses ratios derived from each network's Augex Model (RIN Table 2.4.6. Figure 5 maps each network type allocation of augex to each asset group in RIN Table 2.4.6 for which there is a capex breakdown by network type.

Figure 5 – Network Type Allocation of Augex Mapped to Asset Group in RIN Table 2.4.6
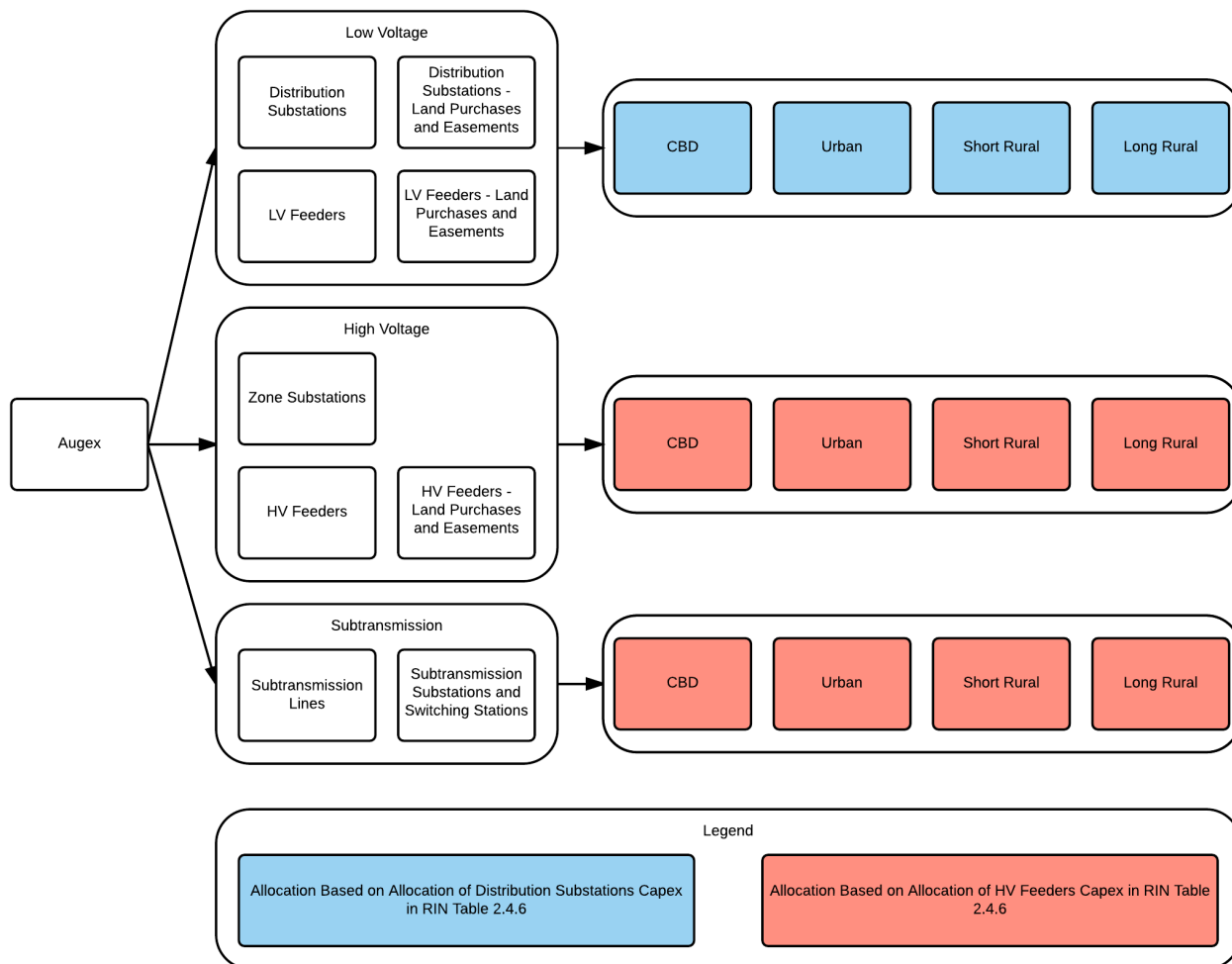
6.2 Incremental Repex

AER defines annual incremental repex as the capital expenditure associated with asset replacement driven by economic condition. This applies irrespective of any upgrade to the asset above the modern equivalent asset that may be done when assets are replaced at the end of their economic lives[3].

There are two types of repex that need to be accounted for in the AIC calculation: first, repex on existing assets and secondly, repex on future augmentation assets.

Although repex on existing assets is not usually associated with demand growth, modern equivalent assets typically have higher capacity than those they replace. Energeia therefore assumes annual incremental repex is 2.5%[4] of total repex, although this percentage is configurable.

Repex on future augmentation assets is incorporated into the AIC calculation by applying the Excel PMT function to augex. The PMT function calculates annualised capital expenditure, assuming constant payments, constant interest rates (equal to the DNSP-specific real WACC) and a configurable average asset lifetime.

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[3] AER Better Regulation: Expenditure Forecast Assessment Guideline for Electricity Distribution, p18

[4] Including capitalized network and corporate overheads

6.2.1 Voltage Level Allocation

Repex is specified on an asset category level in RIN Table 2.2.1. In the tool, each asset category is categorised based on the corresponding voltage level (see Table 7 in Appendix 3 for mapping). Where an asset category spans across multiple voltage levels (such as 'staking of wooden poles'), repex is generally allocated based on the overhead line circuit length at each voltage level, sourced from RIN Table 3.5.1.1.

6.2.2 Network Type Allocation

To decompose repex at each voltage level into CBD, urban, SR and LR repex, the tool uses ratios derived from each network's Augex Model (RIN Table 2.4.6). Figure 6 maps each network type allocation of repex to each asset group in RIN Table 2.4.6 for which there is a capex breakdown by network type.

Figure 6 – Network Type Allocation of Repex Mapped to Asset Group in RIN Table 2.4.6
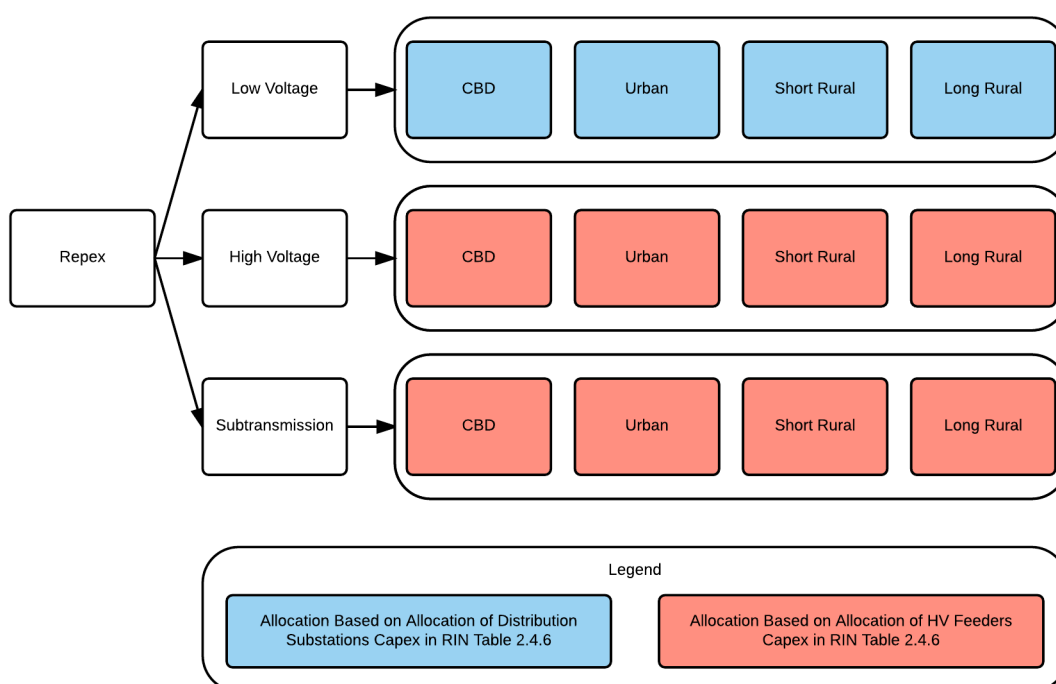
6.3 Incremental Connex

AER defines annual incremental connex as the capital expenditure required to augment the network to support the additional demand associated with new customer connections and other customer-related works[5].

6.3.1 Voltage Level Allocation

Connex is displayed in RIN Table 2.5.2 based on customer type (residential, commercial/industrial, subdivision and embedded generation) and voltage level (ST, HV and LV). For the purpose of calculating AIC values, connex is aggregated by voltage level.

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[5] AER Better Regulation: Expenditure Forecast Assessment Guideline for Electricity Distribution, p20

6.3.2 Network Type Allocation

To decompose connex at each voltage level into CBD, urban, SR and LR connex, the tool uses the ratio of forecast new connections segmented by network type derived from data in RIN Table 3.4.2.2 for each DNSP.

Capital contributions by customers, sourced from RIN Table 2.1.1, are deducted from connections expenditure in the same ratio as the connections expenditure.

The inclusion of connex and customer contributions is configurable in the tool.

6.4 Incremental Overheads

Capitalised network and corporate overheads, sourced from RIN Table 2.1.1, are apportioned to augex, repex and connex based on each investment driver's relative contributions to total capex.

6.5 Projection

Annual incremental augex, repex and connex are then projected 20 years beyond the 5-year forecast period using the average growth rate during the 5-year forecast period to represent incremental capital expenditure over the long term. However, the time horizon is configurable.

The augex scaling factor can be adjusted to reflect the user's view on how representative the DNSP's 5 year forecast augex is of the long term average. Only affects the augex forecast after the first 5 years. If the user considers the DNSP's 5 year forecast augex to be above average, this percentage should be set to below 100%; this percentage should be set to above 100% if the user considers the DNSP's 5 year forecast augex to be below average. The augex scaling factor only affects the augex forecast after the first 5 years.

7   Incremental Opex

AER defines opex as the non-capital cost of running an electricity network and maintaining the assets[6]. More specifically, annual incremental opex is the additional operating and maintenance costs (including vegetation management, maintenance, emergency response, non-network costs, and network and corporate overheads) that are associated with the assets that must be built or upgraded to support changes in demand, and the existing assets that are likely to fail more often due to higher utilisation rates.

7.1 Voltage Level Allocation

Assets at higher voltage levels tend to be more capital intensive whereas those at lower voltage levels tend to be more maintenance intensive. This is reflected in Energeia's assumptions relating to opex as a proportion of growth-related capex (including overheads) at each voltage level. The set of proportions listed in Table 4 are used across all four DNSPs, although they are configurable.

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[6] AER Better Regulation: Expenditure Forecast Assessment Guideline for Electricity Distribution, p5

Table 4 – Opex as a Proportion of Capex by Voltage Level

Voltage Level	Opex as Proportion of Capex
ST	1.50%
HV	2.00%
LV	2.50%

As opex on newly commissioned assets is usually phased in during the few years immediately following the asset's commissioning, the percentages listed in Table 5 are also applied to growth-related capex to produce the annual incremental opex at each voltage level.

Table 5 – Opex Scaling Factors for Each Year Following the Asset's Commissioning

Incremental Annual Opex as a Percentage of Capex					
Year	0	1	2	3	4
Percentage	0%	60%	0%	0%	40%

7.2 Network Type Allocation

Annual incremental opex at each voltage level was converted to annual incremental opex at each network type based on each network type's contribution to total capex at each voltage level.

7.3 Projection

Annual incremental opex is then projected 20 years beyond the 5-year forecast period using the average growth rate during the 5-year forecast period to represent incremental opex over the long term. However, the time horizon is configurable.

8   Assumptions and Limitations

The tool assumes that the RIN data is correct and derived using a consistent approach across the DNSPs.

The tool assumes that the 5-year forecast period in the RINs is indicative of the next 5-25 years (depending on the tool's configuration) for network demand and growth-related expenditure.

The tool assumes a constant allocation of demand, capex and opex across the different network types over time.

The accuracy of the tool is limited by the extent to which network demand and growth-related expenditure are broken down by voltage level and network type in the RINs. Table 6**Error! Reference source not found.** shows which model inputs were provided by voltage level and which were provided by network type in the RINs.

Table 6 – Granularity of RIN Data for each Model Input

Input	System Level Data Provided in the RINs	Voltage Level Breakdown Provided in the RINs	Network Type Breakdown Provided in the RINs
Incremental Augmentation Expenditure	✓	✓	✗
Incremental Replacement Expenditure	✓	✓	✗
Incremental Connections Expenditure	✓	✓	✗
Incremental Operations and Maintenance Expenditure	✗	✗	✗
Incremental Demand	✓	✗	✗

Appendix 1 – Approaches to Calculating LRMC

Three approaches for the calculation of LRMC were considered.

- Average Incremental Cost (AIC)

- Turvey Incremental Cost (TIC)

- Long Run Incremental Cost (LRIC)

The average incremental cost was deemed most appropriate given the aims of the project. This section outlines the three approaches and the justification for the selection of the AIC.

A1.1 Average Incremental Cost Approach

Calculating the AIC involves the following three steps:

1. Forecast peak demand over a future time horizon (e.g. 25 years)

2. Develop a least cost program of network capacity augmentation to ensure that future network capacity can support future peak demand, to the extent dictated by the relevant reliability standards

3. Calculate AIC by dividing the present value of the expected costs of the augmentation program by the present value of the additional demand supplied. The expected costs of the augmentation program refers to both capital costs and marginal operating costs, while the additional demand supplied refers to the demand over and above that which is currently being supplied rather than that which could be supplied.

There are two key advantages to the AIC over other LRMC approaches: the outputs are not as sensitive to initial conditions and it is not as effort and data intensive.

The main disadvantage of the AIC is that it does not attempt to connect a particular increment of demand with the resulting change in cost. Instead, the AIC approach uses average future capital costs to estimate the likely marginal costs associated with a change in demand. This does not align with the inherently lumpy nature of network investment where an extra 1 MW of demand at a constrained zone substation may require millions of dollars of additional investment while an extra 1 MW of demand at a newly established zone substation would require very little additional expenditure.

A1.2 Turvey Incremental Cost Approach

Calculating the TIC involves the following four steps:

1. Forecast peak demand over a future time horizon (e.g. 25 years)

2. Develop a least cost program of network capacity augmentation to ensure that future network capacity can support future peak demand, to the extent dictated by the relevant reliability standards

3. Increase or decrease forecast peak demand by a small, but permanent amount and recalculate the least cost program of network capacity augmentation required to satisfy the revised level of peak demand

4. Calculate TIC by dividing the present value of the change in expected costs of the augmentation program by the present value of the change in additional demand supplied. The expected costs of the augmentation program refers to both capital costs and marginal operating costs, while the additional demand supplied refers to the demand over and above that which is currently being supplied rather than that which could be supplied.

The main advantage of the TIC is that it focuses on the specific cost implications of an increment of demand. It therefore more accurately reflects the nature of network investment and the concept of a long run marginal cost.

The primary disadvantage of the TIC is that the outputs are highly sensitive to initial conditions, the timing of planned investment, the lumpiness of investment and the incremental size of demand. In this way, calculating LRMC using the Turvey approach is typically a more subjective and arbitrary exercise than calculating LRMC using the other approaches.

Another shortcoming of the TIC is that it is resource and data intensive, requiring two estimates of capital and operating expenditure programs, given two sets of demand forecasts.

A1.3 Long Run Incremental Cost Approach

Calculating the LRIC involves calculating the annualised cost of augmentation necessary to support a specified increment in demand. The most common example of this approach is the Common Distribution Charging Methodology (CDCM), which forms the basis for distribution tariffs in the United Kingdom. This model is based upon the creation of a hypothetical network for the supply of 500 MW of demand, using the spatial characteristics and standardised equipment typical for the distributor.

The key benefit of the LRIC is that it can be used to accurately estimate a LRMC specific to a particular network type (e.g. CBD, urban, short rural or long rural).

The main shortfalls of the LRIC are that it is complex and costly to carry out, and the outputs are sensitive to starting conditions.

A1.4 Energeia's Approach to Calculating LRMC

Energeia views the AIC approach as the most feasible and appropriate approach to use because it satisfies the ISF's requirements, is commonly employed by Distribution Network Service Providers (DNSPs), is less sensitive to the modeller's assumptions than the other approaches and is less complex than the other approaches. The publically available regulatory information notice (RIN) data includes all key information needed to perform an LRMC calculation using the AIC method at the system level, some information at the voltage level and little information at the spatial level (see Section 8). This meets ISF's requirements of transparency (publically available data), consistency (data provided using the same calculation methodology) and auditability (AER audits the RIN data).

Appendix 2 – Approach to Segmenting AIC by Network Type

Two approaches for the segmentation of system AIC by network type were considered.

- Augex Model
- Augex Projects

The Augex Model was deemed most appropriate given the aims of the project. This section outlines the two approaches and the justification for the selection of the Augex Model.

A2.1 Augex Model Approach

The Augex Model is a predictive model employed by the AER that relies on capacity factors to identify parts of the network that may require augmentation, and unit costs to derive an augex forecast for each DNSP over the 5-year forecast period. Given the different network configurations, operating conditions and non-standard techniques for data collection and presentation by different DNSPs, the outputs of the Augex Model are not necessarily accurate or comparable, especially during periods of changing levels of demand growth and/or changing network reliability standards.

The Augex Model approach to segmenting system AIC by network type involves the following eight steps:

1. As part of each network's Augex Model, forecast capex on HV feeders and distribution substations is split into CBD, urban, SR and LR (in RIN Table 2.4.6). Using these values, calculate two *capex* ratios for each DNSP: one for HV feeders and one for distribution substations.

2. Forecast capacity added in MVA on HV feeders and distribution substations is similarly separated in the Augex Model. Use these values to calculate two *incremental demand* ratios for each DNSP: one for HV feeders and one for distribution substations.

3. Apply the *capex* ratio for HV feeders obtained in Step 1 to augex on ST lines, ST substations, switching stations, HV feeders and HV feeders – land. Apply the *capex* ratio for distribution substations obtained in Step 1 to augex on distribution substations, distribution substations – land, LV feeders and LV feeders - land. Assume the augex zone substations is split evenly among CBD, urban, SR and LR.

4. Apply the *capex* ratio for HV feeders obtained in Step 1 to HV repex, and the *capex* ratio for distribution substations to LV repex. Assume ST repex is split evenly among CBD, urban, SR and LR.

5. Leave opex as a certain proportion of capex.

6. Allocate future connex across the four network types (CBD, urban, SR and LR) based on their relative contributions to the number of forecast connections over the next 5 years.

7. Apply the *incremental demand* ratio for HV feeders obtained in Step 2 to HV incremental demand, and the *incremental demand* ratio for distribution substations obtained in Step 2 to LV incremental demand. Assume ST incremental demand is split evenly among CBD, urban, SR and LR.

8. Calculate each DNSP's AIC for CBD, urban, SR and LR network types by dividing the total incremental capex and opex for each network type over the incremental demand for each network type.

The primary advantage of the Augex Model approach is that it provides detail on the average cost in $/MVA added of distribution substations and HV feeders at the network type level, which is likely to be greater than the variation in the average cost in $/MVA added of zone substations at the network type level.

The main disadvantage of the Augex Model approach is that the outputs of the Augex Model are calculated at a very high level and therefore should not be regarded as highly accurate.

Another disadvantage is that the Augex Model does not provide a breakdown of the average cost in $/MVA of subtransmission assets by network type.

A2.2 Augex Projects Approach

The Augex Projects approach to segmenting system AIC by network type involves the following three steps:

1. Using each network's list of proposed augex projects for the current regulatory period (in RIN Table 2.3.1), calculate the average $/MVA for CBD, urban, SR and LR zone substations.

2. Calculate a ratio specific to each network based on the values found in Step 1.

3. Apply the ratios found in Step 2 to each DNSP's system AIC.

The main advantage of the Augex Projects approach is that it relies on real project costs.

The main disadvantage is that data is quite limited in this area, with the number of new or upgraded zone substations ranging from 3–20 per DNSP. Moreover, based on the data that is available, there seems to be little variation in the average $/MVA for CBD, urban, SR and LR zone substations.

A2.2 Energeia's Approach to Segmenting System AIC by Network Type

As the Augex Model provides detail on the average costs ($/MVA) at the HV and LV levels, where average costs are more likely to differ among different network types than at the ST level, Energeia chose to adopt this methodology over the Augex Projects methodology. To reduce the effect of inaccuracy or inconsistency across Augex Model outputs across DNSPs, only the ratios of capex and demand among network types were used – rather than the nominal values.

Appendix 3 – Repex Voltage Allocation

Table 7 shows how each repex asset category in RIN Table 2.2.1 is mapped to a voltage level.

Table 7 – Mapping of Repex Asset Categories in RIN Table 2.2.1 to Voltage Levels

Asset Group	Asset Category	Voltage Level
POLES BY: Highest operating voltage; Material type; Staking (if wood)	Staking of a wooden pole	LV+HV
	< = 1 kV; Wood	LV
	> 1 kV & < = 11 kV; Wood	LV
	> 11 kV & < = 22 kV; Wood	HV
	> 22 kV & < = 66 kV; Wood	ST
	> 66 kV & < = 132 kV; Wood	ST
	> 132 kV; Wood	ST
	< = 1 kV; Concrete	LV
	> 1 kV & < = 11 kV; Concrete	LV
	> 11 kV & < = 22 kV; Concrete	HV
	> 22 kV & < = 66 kV; Concrete	ST
	> 66 kV & < = 132 kV; Concrete	ST
	> 132 kV; Concrete	ST
	< = 1 kV; Steel	LV
	> 1 kV & < = 11 kV; Steel	LV
	> 11 kV & < = 22 kV; Steel	HV
	> 22 kV & < = 66 kV; Steel	ST
	> 66 kV & < = 132 kV; Steel	ST
	> 132 kV; Steel	ST
	OTHER - Bollards and unknown	Other
	Other	Other
POLE TOP STRUCTURES BY: Highest operating voltage	< = 1 kV	LV
	> 1 kV & < = 11 kV	LV
	> 11 kV & < = 22 kV	HV
	> 22 kV & < = 66 kV	ST
	> 66 kV & < = 132 kV	ST
	> 132 kV	ST
OVERHEAD CONDUCTORS BY: Highest operating voltage; Number of phases (at HV)	> 11 kV & < = 22 kV ; SWER	HV
	> 11 kV & < = 22 kV ; Single-Phase	HV
	> 11 kV & < = 22 kV ; Multiple-Phase	HV
UNDERGROUND CABLES BY: Highest operating voltage	> 11 kV & < = 22 kV	HV
	> 22 kV & < = 33 kV	ST
	> 33 kV & < = 66 kV	ST
	> 132 kV	ST
SERVICE LINES BY: Connection voltage; Customer type; Connection complexity	< = 11 kV ; Residential ; Simple Type	LV
	< = 11 kV ; Commercial & Industrial ; Simple Type	LV
	< = 11kV; RESIDENTIAL ; SIMPLE ; OVERHEAD	LV
	< = 11kV; RESIDENTIAL ; SIMPLE ; UNDERGROUND	LV
	< = 11kV; COMMERCIAL & INDUSTRIAL ; SIMPLE ; OVERHEAD	LV
	< = 11kV; COMMERCIAL & INDUSTRIAL ; SIMPLE ; UNDERGROUND	LV
	< = 11 kV ; Residential ; Complex Type	LV
	< = 11 kV ; Commercial & Industrial ; Complex Type	LV
	< = 11 kV ; Subdivision ; Complex Type	LV
	> 11 kV & < = 22 kV ; Commercial & Industrial	HV
	> 11 kV & < = 22 kV ; Subdivision	HV
	> 22 kV & < = 33 kV ; Commercial & Industrial	ST
	> 22 kV & < = 33 kV ; Subdivision	ST
	> 33 kV & < = 66 kV ; Commercial & Industrial	ST
	> 33 kV & < = 66 kV ; Subdivision	ST
	> 66 kV & < = 132 kV ; Commercial & Industrial	ST
	> 66 kV & < = 132 kV ; Subdivision	ST
	> 132 kV ; Commercial & Industrial	ST
	> 132 kV ; Subdivision	ST

Asset Group	Asset Category	Voltage Level
TRANSFORMERS BY: Mounting type; Highest operating voltage; Ampere rating; Number of phases (at LV)	Pole Mounted ; < = 22kV ; < = 60 kVA ; Single Phase	LV
	Pole Mounted ; < = 22kV ; > 60 kVA and < = 600 kVA ; Single Phase	LV
	Pole Mounted ; < = 22kV ; > 600 kVA ; Single Phase	LV
	Pole Mounted ; < = 22kV ; < = 60 kVA ; Multiple Phase	LV
	Pole Mounted ; < = 22kV ; > 60 kVA and < = 600 kVA ; Multiple Phase	LV
	Pole Mounted ; < = 22kV ; > 600 kVA ; Multiple Phase	LV
	Kiosk Mounted ; < = 22kV ; < = 60 kVA ; Single Phase	LV
	Kiosk Mounted ; < = 22kV ; > 60 kVA and < = 600 kVA ; Single Phase	LV
	Kiosk Mounted ; < = 22kV ; > 600 kVA ; Single Phase	LV
	Kiosk Mounted ; < = 22kV ; < = 60 kVA ; Multiple Phase	LV
	Kiosk Mounted ; < = 22kV ; > 60 kVA and < = 600 kVA ; Multiple Phase	LV
	Kiosk Mounted ; < = 22kV ; > 600 kVA ; Multiple Phase	LV
	Ground Outdoor / Indoor Chamber Mounted; < 22 kV ; < = 60 kVA ; Single Phase	LV
	Ground Outdoor / Indoor Chamber Mounted; < 22 kV ; > 60 kVA and < = 600 kVA ; Single Phase	LV
	Ground Outdoor / Indoor Chamber Mounted; < 22 kV ; > 600 kVA ; Single Phase	LV
	Ground Outdoor / Indoor Chamber Mounted; < 22 kV ; < = 60 kVA ; Multiple Phase	LV
	Phase	LV
	Ground Outdoor / Indoor Chamber Mounted; < 22 kV ; > 600 kVA ; Multiple Phase	LV
	Ground Outdoor / Indoor Chamber Mounted; > = 22 kV & < = 33 kV ; < = 15 MVA	HV
	Ground Outdoor / Indoor Chamber Mounted; > = 22 kV & < = 33 kV ; > 15 MVA and < = 40 MVA	HV
	Ground Outdoor / Indoor Chamber Mounted; > = 22 kV & < = 33 kV ; > 40 MVA	HV
	Ground Outdoor / Indoor Chamber Mounted; > 33 kV & < = 66 kV ; < = 15 MVA	HV
	Ground Outdoor / Indoor Chamber Mounted; > 33 kV & < = 66 kV ; > 15 MVA and < = 40 MVA	HV
	Ground Outdoor / Indoor Chamber Mounted; > 33 kV & < = 66 kV ; > 40 MVA	HV
	Ground Outdoor / Indoor Chamber Mounted; 66 kV & < = 132 kV ; < = 100 MVA	HV
	Ground Outdoor / Indoor Chamber Mounted; > 66 kV & < = 132 kV ; > 100 MVA	HV
	Ground Outdoor / Indoor Chamber Mounted; > 132 kV ; < = 100 MVA	HV
	Ground Outdoor / Indoor Chamber Mounted; > 132 kV ; > 100 MVA	HV
	POLE MOUNTED ; > 22 kV ; < = 60 kVA	HV
	POLE MOUNTED ; > 22 kV ; > 60 kVA AND < = 600 kVA	HV
	REGULATORS (ALL VOLTAGES)	HV
SWITCHGEAR BY: Highest operating voltage; Switch function	< 1 kV ; CIRCUIT BREAKER	LV
	> 1 kV & < ≈ 11 kV ; CIRCUIT BREAKER	LV
	< = 11 kV ; FUSE	LV
	< = 11 kV ; Switch	LV
	< = 11 kV ; Circuit Breaker	LV
	> 22 kV & < = 33 kV ; Switch	ST
	> 22 kV & < = 33 kV ; Circuit Breaker	ST
	> 33 kV & < = 66 kV ; Switch	ST
	> 33 kV & < = 66 kV ; Circuit Breaker	ST
	> 66 kV & < = 132 kV ; Switch	ST
	> 66 kV & < = 132 kV ; Circuit Breaker	ST
	> 11 kV & < = 22 kV ; Switch	HV
	> 11 kV & < = 22 kV ; Circuit Breaker	HV
	> 132 kV ; Switch	ST
	> 132 kV ; Circuit Breaker	ST
	> 11 KV & < = 22 KV ; FUSE	HV
	> 22 KV & < = 33 KV ; FUSE	ST
	> 33 KV & < = 66 KV ; FUSE	ST
	< = 11 KV ; CIRCUIT BREAKER - INDOOR SWITCHBOARD HOUSED	LV
	> 11 KV & < = 22 KV ; CIRCUIT BREAKER - INDOOR SWITCHBOARD HOUSED	HV
	> 22 KV & < = 33 KV ; CIRCUIT BREAKER - INDOOR SWITCHBOARD HOUSED	ST
	> 33 KV & < = 66 KV ; CIRCUIT BREAKER - INDOOR SWITCHBOARD HOUSED	ST
SCADA, NETWORK CONTROL AND PROTECTION SYSTEMS BY: Function	Field Devices	ST
	Communications Network Assets	ST
	Master Station Assets	ST
	Local Network Wiring Assets	ST
	Communications Site Infrastructure	ST
	Communications Linear Assets	ST
	AFLC	LV

Asset Group	Asset Category	Voltage Level
PUBLIC LIGHTING BY: Asset type ; Lighting obligation	Luminaires ; Major Road	Other
	Luminaires ; Minor Road	Other
	Brackets ; Major Road	Other
	Brackets ; Minor Road	Other
	Lamps ; Major Road	Other
	Lamps ; Minor Road	Other
	Poles / Columns ; Major Road	Other
	Poles / Columns ; Minor Road	Other
OTHER BY: DNSP defined	DISTRIBUTION SUBSTATIONS - OTHER	LV
	DISTRIBUTION VOLTAGE REGULATION	LV
	TOWERS - > = 33 kV ; ANTI-CLIMB DEVICES	ST
	TOWERS - > = 33 kV TOWER FOOTINGS	ST
	TOWERS - > = 33 kV TOWER REFURBISHMENT	ST
	ZONE & SUBTRANSMISION SUBSTATIONS - OTHER	HV+ST
	BUILDINGS	Other
	Zone CLC equipment (Electronic)	HV
	Zone General (including spares)	HV
	Zone prot. & control equipment (Electronic)	HV
	STS Protection & Control (Electronic)	ST
	STS Reactors and Capacitors	ST
	Sub-Transmission Main OH Easement	ST
	STS Building (incl sw. stns)	ST
	STS Communications	ST
	STS DC Systems	ST
	STS General (including spares)	ST
	Zone Reactors and Capacitors	HV
	Environmental Management	LV+HV+ST
	PLANT AND STATIONS MISCELLANEOUS	HV
	Zone Substation Major Building / Property / Facilities	HV
	VBRC SWER ACRs	HV
	TV Interference Replacement Capital	Other
	CURRENT TRANSFORMERS	HV
	VOLTAGE TRANSFORMERS	HV
	CAPACITOR BANKS	HV
	SVC	HV
	Orange North - TransGrid rebuild Orange 66kV busbar - REFURBISHMENT	ST
	Rectification of low clearance infringements on subtransmission feeders - REFURBISHMENT	ST
	Tamworth - TransGrid 132/66kV substation - relocate 66kV feeders - REFURBISHMENT	ST
	Terranora to QLD border - refurbish 110kV towers in line with Powerlink - REFURBISHMENT	ST
	Yarrandale to Gilgandra - rebuild existing 66kV feeder - REFURBISHMENT	ST
	Wagga Copeland St - TransGrid 132/66kV sub - relocate 66kV feeders - REFURBISHMENT	ST
	Queanbeyan TG to Googong Town ZS Refurbish Line 975 - REFURBISHMENT	ST
	Pole top refurbishment of Taree to Forster 66kV feeders - REFURBISHMENT	ST
	REFURBISHMENT	ST
	Gunnedah to Narrabri Tee via Boggabri - refurbish 66kV feeders - REFURBISHMENT	ST
	Taree - TransGrid 132/66/33kV substation - relocate 33kV feeders - REFURBISHMENT	HV
	Customer Metering and Load Control	LV
	S&W Accrual and Other Adjustments	Other
	Dist Lines & Cables, Sub Trans Lines,LV Lines (bal. items) - REFURBISHMENT	Other
	Subtransmission Lines (balancing Items) - - REFURBISHMENT	ST